TECHNICAL REVIEW DOCUMENT
for
RENEWAL
of
OPERATING PERMIT 95OPPB025
to be issued to:

WestPlains Energy (Division of UtiliCorp United)
Pueblo Power Plant
Pueblo County
Source ID 1010008

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I. PURPOSE

This document will establish the basis for decisions made regarding the Applicable Requirements, Emission Factors, Monitoring Plan and Compliance Status of Emission Units covered within the renewed Operating Permit proposed for this site. It is designed for reference during review of the proposed permit by the EPA, the public and other interested parties. The conclusions based on this report are based on information provided in the permit renewal application submitted on October 18, 2001. This narrative is intended only as an adjunct for the reviewer and has no legal standing.

Any revisions made to the underlying construction permits associated with this facility made in conjunction with the processing of this operating permit renewal application have been reviewed in accordance with the requirements of Regulation No. 3, Part B, Construction Permits, and have been found to meet all applicable substantive and procedural requirements. This Operating Permit incorporates and shall be considered to be a combined Construction/Operating Permit for any such revision, and the permittee shall be allowed to operate under the revised conditions upon issuance of this Operating Permit without applying for a revision to this permit or for an additional or revised Construction Permit.

II. SOURCE DESCRIPTION

This facility is located in Pueblo, Colorado. Pueblo is classified as an attainment area for all criteria pollutants. There are no affected states within 50 miles of the facility. The Great Sand Dunes National Park is a designated Federal Class I area within 100 kilometers of the facility. Florissant Fossil Beds is a Federal land area within 100 kilometers of the facility. Florissant Fossil Beds has been designated by the State to have the same sulfur dioxide increment as Federal Class I areas.

There have been several steam driven generating units at the facility since the early 1920s. Unit #1922 (boiler #1, #2 and #3, and turbine #4) was converted from coal burning in the 1960s. The unit was permanently removed from service about January 1, 1990. Unit #1941 (boiler #4 and turbine #5) was permanently removed from service on December 14, 1994. A new natural gas fired boiler to replace Unit #1941 boiler was placed in service in 2001. The new boiler uses the existing turbine and facility components for the previous boiler.

The following is the Potential-to-Emit for the sources of emissions at the Power Plant:

POLLUTANT	POTENTIAL TO EMIT, TPY				TOTAL PTE, TPY	1999 ACTUAL EMISSIONS, TPY
	246 MMBtu/Hr BOILER		134.7 MMBtu/Hr BOILER	5 DIESEL ENGINES		
	NG	#2 FO	NG			
PM	3.57	14.77	4.8	112.98	132.6	2.33
PM_{10}	3.57	7.39	4.8	107.93	120.1	1.99
SO_X	0.71	1060.63	0.4	105.23	1166.2	---
NO_X	654.78	177.26	18.1	1581.75	2254.6	108.8
VOC	1.67	1.48	3.4	108.26	113.3	1.77
CO	47.62	36.93	45.1	344.01	436.7	9.1

NG = natural gas #2 FO = #2 Distillate

III. EMISSION SOURCES

Unit B001 - 246 MMBtu/Hr Babcock and Wilcox Boiler

1. Applicable Requirements – The boiler has grandfather status from the regulatory requirement to have a construction permit. The boiler is subject to the requirements of Colorado Regulation No. 1 which uses the following equation to establish a particulate emissions limit:

$PE = 0.5(FI)^{-0.26}$ PE = Particulate Emissions in pounds per million Btu heat input
FI = Fuel Input in Million Btu (MMBtu) per hour (Hr)

This boiler is subject to the sulfur dioxide standard set by Regulation No. 1, 'VI.A.3.b.(i) when burning fuel oil. The standard is set at 1.5 pounds of sulfur dioxide emissions per million Btu of heat input.

The opacity compliance standard is set not to exceed 20% by Regulation No. 1 §II.A.1, except for periods of building of a new fire, startup, or any process modification. During such periods the opacity of emissions is not to exceed 30% as set by Regulation No. 1 §II.A.4.

This boiler is not subject to the Title IV Acid Rain provisions.

2. Emission Factors - Emissions from the boiler result from burning natural gas and No. 2 distillate. The primary criteria pollutants of concern are nitrogen oxides (NOx) and sulfur oxides (SO_2). Standard factors from the EPA AP-42 manual for emission factors were selected for estimating the actual emissions. The sulfur dioxide emission factor incorporates the fuel oil sulfur content. In addition, the fuel oil heat and sulfur content are needed to determine compliance with the Regulation #1 sulfur dioxide limit. The Title V application reported the sulfur content as 0.31% and the heat content as 136,915 Btu per gallon for the stored fuel oil.

The boiler has the capability to burn fuel oil and natural gas simultaneously. There are no readily available published emission factors for this scenario. However, based on engineering judgment, the emissions should be representative of each fuel fraction. As such, total emissions under this scenario will be estimated as the sum of emissions from the fuel oil fraction and natural gas fraction.

3. Monitoring Plan - The grandfathered status of the boiler reduces the amount of monitoring required. Since the unit operates as the primary power supply it is expected that there would be limited startups. Startups for large boilers may take an extended time and may result in significant opacity. Operating staff experience may have an affect on the both the startup time required and opacity levels.

The general operating procedure for the boiler is to use natural gas for boiler startup. The pilot lights for the boiler burners are natural gas fired. The burners can not be ignited without the pilot lights. When the boiler is placed in service from a cold standby, the unit is heated by burning natural gas. It takes approximately 12 hours to bring the boiler up to the steaming level necessary to operate the turbine, synchronize the generator, and supply electrical power. No cold starts are made with fuel oil. Once the turbine is in operation, the natural gas supply may be replaced by fuel oil if necessary. If the boiler switches to burning the fuel oil, the switch-over is accomplished burner-by-burner until the desired number of burners are using the fuel oil. The process is reversed to return to natural gas service. The boiler may be placed in service in an emergency mode in as little as two hours. However, the stress on the components is quite severe and leads to substantial damage. Emergency startups are avoided in so far as possible.

When natural gas delivery must be interrupted or is curtailed by the vendor, a number of options are available to the plant manager. The options include: continue operating the boiler on the amount of natural gas available, and either purchase the supplemental electrical power needed, or operate the standby generators; operate the boiler at full production by switching partially or completely to fuel oil; or combinations of the various options.

The Division accepts the position that, based on AP-42 emission factors and engineering judgment, the combustion of natural gas in a properly operated facility does not produce enough particulate matter to require opacity observations. Fuel oil use, however, has a significant potential for opacity problems, particularly for cold startups. The startup and shutdown procedure practiced at this facility minimizes the potential for opacity problems.

The combination of the emission factor and the heat content of the boiler fuel precludes exceeding the short term particulate emission standard while burning fuel oil or natural gas as demonstrated by the following calculations:

Diesel Fuel: $$\frac{2\ \text{lb}}{1000\ \text{gal}} \times \frac{\text{gal}}{136{,}916\ \text{Btu}} = 0.015\ \frac{\text{lb}}{\text{MMBtu}} \ll 0.120\ \frac{\text{lb}}{\text{MMBtu}}$$

Natural Gas: $$\frac{7.6\ \text{lb}}{\text{MMscf}} \times \frac{\text{scf}}{850\ \text{Btu}} = 0.009\ \frac{\text{lb}}{\text{MMBtu}} \ll 0.120\ \frac{\text{lb}}{\text{MMBtu}}$$

Likewise, the following calculation demonstrates that the emission factor/fuel heat content combination assures compliance with the sulfur dioxide short term standard for ASTM Grade 2 distillate which has a sulfur content limit of 0.5%, by weight:

Diesel Fuel: $$\frac{142 \times 0.5\ \text{lb}}{1000\ \text{gal}} \times \frac{\text{gal}}{136{,}916\ \text{Btu}} = 0.52\ \frac{\text{lb}}{\text{MMBtu}} < 1.5\ \frac{\text{lb}}{\text{MMBtu}}$$

WestPlains only needs to retain a file copy of the above calculations for demonstrating this compliance in the absence of any other credible evidence.

WestPlains requested to estimate the emissions based on the maximum sulfur content allowed for ASTM Grade 2 sulfur (0.5%). The requirement for a fuel sampling plan has been removed from the permit. However, WestPlains must maintain records of the certificates of the sulfur content of the Grade 2 delivered demonstrating the 0.5% sulfur content has not been exceeded.

4. Compliance Status - The Division accepts the unit was in compliance at the time the Title V application was submitted.

Unit B002 – 134.7 MMBtu/Hr ABCO Industries, Inc Type D, Natural Gas Fired SN SO200003

1. Applicable Requirements – The applicable requirements for the new boiler were established directly as combined construction permit and modification of the existing Title V permit.

Colorado Regulation No. 1, Section III.A.1.b and Colorado Regulation No. 6, Part B, Section II.C.2 use the following equation to establish a particulate emissions limit:

$PE = 0.5(FI)^{-0.26}$ PE = Particulate Emissions in pounds per million BTU heat input
FI = Fuel Input in Million BTU (MMBTU) per hour (Hr)

Colorado Regulation No. 1 is Federally enforceable, while Regulation No. 6 is a State-only requirement.

The boiler is subject to the New Source Performance Standards (NSPS) Subpart Db -"Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units". Subpart Db does not provide any standards for sulfur dioxide or particulate emissions for units burning only natural gas. Section 60.44b(l)(2) of Subpart Db sets a nitrogen oxides emission standard of 0.10 lb/MMBtu for the boiler.

The opacity compliance standard is set not to exceed 20% by Regulation No. 1 §II.A.1, except for periods of building of a new fire, startup, or any process modification. During such periods the opacity of emissions is not to exceed 30% as set by Regulation No. 1 §II.A.4. Regulation No. 6, 'II.C.3 sets a State-Only requirement for the opacity standard not to exceed 20%.

The unit is exempt from the Title IV Acid Rain provisions because the electrical generation output of 9 MW is less that the 25 MW exemption threshold of Title IV.

2. Emission Factors - Emissions from the boiler result from burning natural gas. The primary criteria pollutants of concern are nitrogen oxides (NO_x) and sulfur oxides (SO_2). WestPlains requested to use standard emission factors from the EPA AP-42 manual for all the criteria pollutants except the nitrogen oxides and carbon monoxide. The boiler manufacturer provided emission factors for the carbon monoxide and nitrogen oxides. The carbon monoxide emission factor was nearly double the AP-42 factor; while the nitrogen oxide emission factor was less than half the AP-42 factor. The Division accepts emission factors greater than AP-42 without the requirement for demonstrating compliance. However, for emission factors less than AP-42, as is the case for the nitrogen oxide emissions, a compliance test is required.

3. Monitoring Plan – The Division does not believe that the firing of natural gas should result in opacity compliance problems. On that basis, the Division accepts the restriction to firing only natural demonstrates compliance with the opacity standard, unless there is any credible evidence to demonstrate that is not the case. The Method 9 opacity monitoring provisions are provided in the unlikely event an opacity compliance issue arises.

The NSPS Subpart Db provisions allow compliance with the nitrogen oxides pounds per million Btu standard to be demonstrated by use of a continuous monitoring system (CEMS) (§60.48b(b)(1) or a predictive emissions monitoring system (PEMS) method based on defined operating conditions (§60.48b(g)(2). UtiliCorp has used predictive methods at another plant they operate and requested this alternative be available for use for this boiler. The NSPS provisions provide the Division with the authority to review, accept and approve the use of a PEMS in lieu of a CEMS. In the event the Division does not accept and approve the use of a PEMS, the CEMS shall be required. An approved monitoring system must be in place within 360 days of the initial startup of the boiler.

Subpart Db Section 60.49b(d) requires the amount of fuel combusted to be monitored on a daily basis and to calculate the annual capacity factor on a 12-month rolling average basis. While the annual capacity factor does not play a significant role for this boiler, the provisions require it to be monitored.

The combination of the emission factor and the heat content of the boiler fuel precludes exceeding the short term particulate emission standard of Colorado Regulation No. 6 while burning natural gas as demonstrated by the following calculations:

$$\text{Natural Gas: } \frac{6.3\text{ lb}}{\text{MMscf}} \text{ X } \frac{\text{scf}}{850\text{ Btu}} = 0.007\,\frac{\text{lb}}{\text{MMBtu}} << 0.14\,\frac{\text{lb}}{\text{MMBtu}}$$

WestPlains only needs to retain a file copy of the above calculations for demonstrating this compliance in the absence of any other credible evidence.

Compliance with the limits for the other criteria pollutants is determined by calculation of the emissions based on the fuel use. Since the emission factors and the fuel usage is based on the heat content of the natural gas, the heat content is to be monitored.

4. Compliance Status – The permit requires that compliance with the permit requirements for carbon monoxide and nitrogen oxides be demonstrated within 180 days of the boiler being placed in service. The nitrogen oxides emission factor used for the annual compliance determination is lower than the value provided by the EPA AP-42 manual. Division policy requires a demonstration of compliance for factors less than those provided in AP-42. Because of the relationship of carbon monoxide and nitrogen oxides during combustion, compliance with the carbon monoxide annual limit is to be demonstrated also.

The performance test to demonstrate compliance with the pounds per million Btu NSPS standard requires the nitrogen oxides emissions to be monitored with a continuous emissions monitoring system for 30 successive steam generating unit operating days. WestPlains noted they had received approval to use the predictive emissions monitoring system (PEMS) for the compliance performance test at other plants they operate outside of Colorado. The NSPS provisions require the use of an alternative compliance performance test, such as the PEMS, to be submitted to EPA for approval. WestPlains must be mindful that the deadlines for conducting the compliance performance tests make no provision for any delays created by seeking EPA approval for the use of the alternative test.

After the initial performance test has been completed, the Division or EPA may request compliance with the standard be demonstrated through the use of the 30-day performance test. The NSPS provisions allow a year (360 days) for the preparation of the predictive emissions monitoring system identifying the operating conditions to be monitored and the method or procedure to be used to predict the emissions of nitrogen oxides. The time frames for this provision do not provide for the development and verification of the predictive method during the initial performance test, but does not preclude such activity. The Division considered the need for a performance test to demonstrate the validity of the prediction plan before the plan was approved. After considering the cost for the additional testing and the amount of emissions involved, the Division elected to accomplish the validation prior to the expiration of the permit in the event changes were necessary before the permit was renewed. Nothing prevents WestPlains from performing the test and including the information in the plan submitted for Division approval.

Unit E01, E02, E03, E04, E05 2000 KW Diesel Driven Generators

1. Applicable Requirements - The diesel generators have regulatory grandfather status and do not require construction permits. The Division interpretation of the Regulation #1 definition of fuel burning equipment excludes internal combustion engines. The annual emissions are to be estimated and emission fees paid.

The opacity compliance standard is set not to exceed 20% by Regulation No. 1 §II.A.1, except for periods of building of a new fire, startup, or any process modification. During such periods the opacity of emissions is not to exceed 30% as set by Regulation No. 1 §II.A.4.
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2. Emission Factors - The emission factors are taken from EPA AP-42 October 1996 version. The sulfur dioxide emission factor require an adjustment for the sulfur content on the diesel fuel.

3. Monitoring Plan – The fuel consumption of the engines and the operating hours are to be monitored. The opacity of the emissions is to be monitored each calendar quarter for an engine operating under load and during conditions satisfactory for performing a valid Method 9 observation.

4. Compliance Status - The Division accepts the units were in compliance at the time of the preparation of the application.

Fuel Oil Storage Tank

1. Applicable Requirements - The tank is subject to the record keeping requirements of 40 CFR Part 60, New Source Performance Standards, Subpart Kb '60.116b. Construction Permit 96PB895 also set an annual VOC emission limit and an annual throughput limit for the tank.

2. Emission Factors – This is a large storage tank and while the emissions from No. 2 distillate are low, the emissions may be significant when a large amount of fuel is processed through the tank. The emissions were calculated by EPA=s TANKS 2 software.

3. Monitoring Plan - The monitoring plan requires the dimensions and capacity analysis of the tank to be kept for the life of the tank. Records of the annual throughput of No. 2 distillate must also be kept on file.

The tank provides fuel oil storage for both the boiler and the diesel generators. The estimated annual fuel oil usage is in the range of 10,000 to 20,000 gallons per year. At the current estimated use rate, it would require 15 to 20 years to replace the contents of the tank. The previous version of the permit provided for periodic sampling of the tank contents. WestPlains requested to use the vendor invoices or delivery receipts to maintain a running calculation of the heat and sulfur content of the fuel stored in the tanks based on the small change in quality created by any delivery. The Division accepted this request and the permit was modified accordingly.

4. Compliance Status - The Division accepts the tank was in compliance at the time of the preparation of the application.

IV. Alternate Operating Scenarios

No alternate operating scenarios were identified.

V. Permit Shield

No permit shield was requested.

VII. Miscellaneous

From time to time published emission factors are changed based on new or improved data. A logical concern is what happens if the use of the new emission factor in a calculation results in a source being out of compliance with a permit limit. For this operating permit, the emission factors or emission factor equations included in the permit are considered to be fixed until changed by the permit. Obvious factors dependent on the fuel sulfur content or heat content can not be fixed and will vary with the test results. The formula for determining the emission factors is, however, fixed. It is the responsibility of the permittee to be aware of changes in the factors, and to notify the Division in writing of impacts on the permit requirements when there is a change in factors. Upon notification, the Division will work with the permittee to address the situation.

A similar situation exists with the EPA TANKS computer program for estimating emissions from storage tanks. Some of the updated versions of the program produce different emission estimates than the existing versions. Just as with the emission factors, the new tank emissions estimates may, in some cases, report values that exceed the permit limits and raise the issue of non-compliance. The problem is being addressed in the same manner as the emission factors. A specific version of TANKS is identified in the Operating Permit. WestPlains must use specified version until the specified version is changed in the same manner the emission factors are change.